Renewable Energy Question #37: How are renewable energy sources and distributed generation impacting grid operation and reliability?

Renewable energy and distributed generation (DG) resources are far from reaching the levels of penetration that might negatively impact grid operation or reliability. As penetration levels have increased in recent years, and as they continue to increase in the future, grid operators have several tools at hand to effectively manage the influx of these new resources while maintaining grid stability and reliability.

Renewable energy and distributed generation present different challenges to grid operators. In the case of renewable energy, challenges to grid stability and reliability typically stem from the intermittent or variable nature of certain renewable energy resources, namely wind and solar photovoltaic (PV). Renewable energy resources such as biomass, hydropower and certain types of solar power are dispatchable just like more traditional fossil fuel fired resources and therefore present no new issues.

While wind and solar PV are intermittent resources, it is first important to remember that *every* resource is variable to some degree. Grid operators are accustomed to dealing with both expected and unexpected outages of generation resources, whether weather-related or for scheduled or unscheduled maintenance. Today, grid operation is done regionally by regional transmission operators, such as MISO that serves the majority of Michigan as well as 12 other states. The MISO Market and Operations Update, (available at https://www.midwestiso.org/MarketsOperations/Pages/MarketsOperations.aspx), shows that the MISO reliability is not affected by the amounts of renewable energy currently serving the grid. From month to month, as the amount of wind varies, MISO does not require additional reserves as the amount of renewable energy increases. This indicates that MISO is comfortably integrating increasing amounts of variable renewable energy without issue.

Grid operators maintain reliability while providing consumers with high levels of variable renewable energy by using operational adjustments and wind forecasts. For an excellent summary of the widespread use of these tools amongst Independent System Operators, see the August 2011 ISO/RTO Council Briefing Paper "Variable Energy Resources, System Operations and Wholesale Markets" http://www.isorto.org/atf/cf/%7B5B4E85C6-7EAC-40A0-8DC3-003829518EBD%7D/IRC_VER-BRIEFING_PAPER-AUGUST_2011.PDF

The experience and research with integration of renewable energy in the Midwest emphasize the management of uncertainty with the use of forecasts of wind production, scheduling practices that allow greater flexibility, transfers between neighboring areas to improve balancing, and active management of wind (i.e. curtailment). These tactics, used individually or in tandem with each other, provide enough flexibility and reliability to the system to accommodate high levels of renewable energy penetration.

Distributed generation poses both benefits and challenges to utility distribution grid operators that operate on a more localized scale than MISO. The benefits of distributed generation include:

1. Reduced line loss: Electricity lost as it is transmitted to consumers can reach 10% or more during times of heavy demand. Distance transmitted is a factor of line loss and having distributed generation resources at the point of consumption can reduce line loss, making the system as a whole more efficient.

2. Demand Reduction: Demand reduction during peak times is a valuable benefit that DG systems can provide, particularly solar PV systems that tend to generate electricity during high- demand periods.

3. Reduced transmission and generation costs: DG systems reduce the need for transmission build out because they generation electricity where it is used. With wide scale deployment, they will also avoid the need for new centralized generation resources.

The being said, there are challenges to connecting significant amounts of distributed generation to the grid. Voltage fluctuation and imbalance, power output fluctuations and islanding (when DG delivers power to the network even after circuit breakers have disconnected that part of the network from the main grid) all pose challenges. However, all of these challenges can be overcome with current technologies and sound interconnection policies. And it is important to note that Michigan and the power grids that connect to it are a long way from levels of DG penetration that would necessitate any significant change in grid operation. As utilities and installers of DG systems become more experienced with installing systems and connecting them to the grid with proper controls, many of the potential issues with a wide scale deployment of distributed generation will become easier and easier to manage.

<u>Resources:</u>

1) Passey, R. 2011. *The potential impacts of grid-connected distributed generation and how to address them: A review of technical and non-technical fixes.* Energy Policy 39 (2011) 6280 – 6290. (PDF included with this response.)

2) Union of Concerned Scientists. 2013. *Ramping up renewables.* Online at http://www.ucsusa.org/assets/documents/clean_energy/Ramping-Up-Renewables-Energy-You-Can-Count-On.pdf; accessed April 16 2013.

3)U.S. Department of Energy. 2007. *The potential benefits of distributed generation and the rate-related issues that may impeded its expansion.* Online at http://energy.gov/sites/prod/files/oeprod/DocumentsandMedia/1817_Report_-final.pdf; accessed 4/17,2013.

4) Vitolo, T., G. Keith, B. Biewald, T. Comings, E. Hausman and P. Knight. 2013. *Meeting load with a resource mix beyond business as usual.* Synapse Energy Economics, Inc. Cambridge MA. Online at http://energy.gov/sites/prod/files/oeprod/DocumentsandMedia/1817_Report_-final.pdf; accessed April 18, 2013.

5) Vittal, V. 2010. *The impact of renewable resources on the performance and reliability of the electricity grid.* The Bridge, Spring 2010. National Academy of Engineering. Online at http://www.nae.edu/File.aspx?id=18585; accessed April 17, 2013.

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The potential impacts of grid-connected distributed generation and how to address them: A review of technical and non-technical factors

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ABSTRACT

Distributed generation is being deployed at increasing levels of penetration on electricity grids worldwide. It can have positive impacts on the network, but also negative impacts if integration is not properly managed. This is especially true of photovoltaics, in part because it's output fluctuates significantly and in part because it is being rapidly deployed in many countries. Potential positive impacts on grid operation can include reduced network flows and hence reduced losses and voltage drops. Potential negative impacts at high penetrations include voltage fluctuations, voltage rise and reverse power flow, power fluctuations, power factor changes, frequency regulation and harmonics, unintentional islanding, fault currents and grounding issues. This paper firstly reviews each of these impacts in detail, along with the current technical approaches available to address them. The second section of this paper discusses key non-technical factors, such as appropriate policies and institutional frameworks, which are essential to effectively coordinate the development and deployment of the different technical solutions most appropriate for particular jurisdictions. These frameworks will be different for different jurisdictions, and so no single approach will be appropriate worldwide.

1. Introduction

Distributed generation technologies are typically defined as small-scale generation options that connect to the electrical distribution network. Here our focus is on the low voltage end of the distribution network, around 10–15 kV. As the range of such technologies increases, and a number have begun to achieve significant penetrations, there has been growing attention to their potential impacts, both positive and negative, on the network. The technologies themselves vary significantly in their operation and potential impacts. Cogeneration, micro-hydro and bioenergy generally have limited weather-related dependencies and hence offer relatively constant and predictable energy output by comparison with wind and solar technologies. Small-scale grid-connected wind is relatively rare at present, and therefore currently having very little impact on distribution networks in most countries. Where small-scale wind is used at higher penetrations, such as on remote mini-grids, well developed technologies such as battery storage and diesel generator backup are currently used. Photovoltaics (PV) on the other hand, is being rapidly deployed in many countries at present, is based on a source of energy that can fluctuate significantly over timescales from seconds through hours to days and seasonally, and is only partially predictable. PV technology itself has almost no inherent energy storage. As such it can have significant negative power quality impacts at high penetrations if appropriate measures are not implemented. Such penetrations are now being seen in some countries due to the extraordinary take-up of small-scale (often residential-scale) PV systems over recent years. As a result, solar power and its associated inverter connection to the grid is the predominant focus of this paper. Nonetheless, the discussed grid impacts capture all those that other DG technologies are likely to present.

Potential positive impacts on grid operation can include reduced network flows and hence reduced losses and voltage drops. Potential negative impacts include voltage fluctuations, voltage rise and reverse power flow, power fluctuations, power factor changes, frequency regulation and harmonics, unintentional islanding, fault currents and grounding issues.

This paper first describes each of these impacts along with the current technical approaches to address them. It is clear there is no 'one size fits all' solution for any of these impacts, and even where technical solutions exist, they may not be implemented because of lack of appropriate policies and institutional frameworks. Thus, the second section of this paper discusses the non-technical factors that influence which types of technological solutions are most likely to be appropriate, and provides suggestions for increasing the likelihood of best practise.

2. Addressing grid integration issues

Electricity grids must have standard conditions of supply to ensure that end-use equipment and infrastructure can operate

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safely and effectively. These conditions are commonly referred to as power quality requirements and are defined in standards or by supply authorities. As discussed below, they most commonly relate to voltage and frequency regulation, power factor correction and harmonics. In all distribution networks, challenges to maintaining these power quality requirements arise from the technical characteristics and end-user operation of electrical loads, and the network equipment and lines. Some loads have significant power demands that increase network current flows pulling down line voltage (such as electric hot water heaters and large air-conditioners). Some have very short-lived but major power draws on start-up (such as standard induction motors) driving voltage fluctuations. Some have significant reactive power needs (again including motors) or create significant harmonics (such as computer power supplies and fluorescent lighting). Power quality at different points of the distribution network at any time is impacted by the aggregate impacts of loads and network equipment in highly complex ways.

DG connected to the distribution network can significantly influence these aggregated impacts. Some impacts can be positive – for example where PV generation is closely correlated to air-conditioning loads and hence reduces the peak network currents seen in the network. At other times DG can have adverse impacts – for example where maximum PV generation occurs at times of minimum load hence reducing current flows below what they would otherwise be, and causing voltage rise in the network. Other issues related to the connection of DG to a network that are not generally also seen with loads include possible unintentional islanding,[1] fault currents, grounding and highly correlated power output fluctuations, all issues that can have significant impacts on power quality yet also system safety, security and control. The following discusses these issues as they relate to DG, as well as options for addressing them. We consider options ranging from those currently being used through to those undergoing trials or still in the R&D stage.

2.1. Voltage fluctuation and regulation

Voltage fluctuation is a change or swing in voltage, and can be problematic if it moves outside specified values. It affects the performance of many household appliances and can consist of variations in the peak and RMS (root mean square) voltage on the line. Supply authorities or government regulators generally stipulate the maximum acceptable deviation from the nominal voltage as seen by the customers. Effects on loads are usually noticed when the voltage fluctuates more than 10% above or below the nominal voltage, and the severity of the effects depend upon the duration of the change. Extended undervoltage causes "brownouts"—characterised by dimming of lights and inability to power some equipment such as fridge compressors. Extended overvoltage decreases the life of most equipment (end-user and networks) and can damage sensitive electronic equipment.

DG systems are relevant to voltage regulation because they are not only affected by voltage fluctuations that occur on the grid, but can cause voltage fluctuations themselves—where the latter effects can be divided into voltage imbalance, voltage rise leading to reverse power flow, and power output fluctuations. These are discussed below.

2.1.1. Grid-derived voltage fluctuations

Inverters are generally designed to operate in what is known as grid 'voltage-following' mode and to disconnect DG when the grid voltage moves outside set parameters. This is both to help ensure they contribute suitable power quality as well as help to protect against unintentional islanding and protect the inverter (discussed below) (Hudson, 2010). Where there are large numbers of DG systems or large DG systems on a particular feeder, their automatic disconnection due to out of range voltage can be problematic because the network will then have to provide additional power (SEGIS, 2007). For example, where there is voltage sag on the grid due to a sudden increase in demand, inverters may disconnect while the loads do not, exacerbating the problem and potentially overloading the network causing a brownout or blackout (Miller and Ye, 2003).

To avoid this happening, voltage sag tolerances could be broadened and where possible, Low Voltage Ride-through Techniques (LVRT) could be incorporated into inverter design. LVRT allows inverters to continue to operate for a defined period if the grid voltage is moderately low but they will still disconnect rapidly if the grid voltage drops too low. In Germany, LVRT standards are now incorporated into grid-connection standards (Tröster, 2009); this is also true in some parts of the USA. Many inverters do not come standard with these capabilities but simple software updates generally could incorporate this feature if required by standards.

Some inverter designs can also be configured to operate in 'voltage-regulating' mode, where they actively attempt to influence the network voltage at the point of connection. Inverters operating in voltage-regulating mode help boost network voltage by injecting reactive power during voltage sags,[2] as well as reduce network voltage by drawing reactive power during voltage rise. However, this capability is not allowed under some national standards—for example, Australian Standard AS4777.2 requires that inverters operate at close to unity power factor (i.e. inject only real power into the grid) unless they have been specifically approved by electricity utilities to control power factor or voltage at the point of connection. In addition, all inverters have limits on their operation and even in voltage regulation mode external factors on the grid may force the voltage outside normal limits—in which case the inverter disconnects (McGranaghan et al., 2008).

Thus, connection standards need to be developed to incorporate and allow inverters to provide reactive power where appropriate. Such standards would need to ensure that this capability did not interfere with any islanding detection systems (discussed below). Utility staff may also need to be trained regarding integration of such inverters with other options used to provide voltage regulation—such as SVCs (Static VAr Compensator) or STATCOMS (static synchronous compensators).

2.1.2. Voltage imbalance

Voltage imbalance is when the amplitude of each phase voltage is different in a three-phase system or the phase difference is not exactly 120° (PVPS-T10, 2009). Single phase DG (or loads for that matter) installed disproportionately on a single phase may cause severely unbalanced networks leading to damage to controls or transformers (SEGIS, 2007). Voltage imbalance will have a negative impact on small distributed three-phase generators, such as temperature rise of rotors, noise, and vibration. It can also have an impact on some loads such as motors and power electronic devices (PVPS-T10, 2009).

Thus, at high PV penetrations, the cumulative size of all systems connected to each phase should be as equal as possible. All systems above a minimum power output level of between 5 and 10 kW typically should have a balanced three-phase

[1] Unintentional islanding is when a section of the electricity network remains 'live', despite being disconnected from the main network, because of distributed generation that continues to operate.

[2] For example due to disturbances in the grid or sudden changes in the renewable energy resource (e.g. cloud cover).

output. The maximum single phase power rating will depend on local conditions and the network to which they are connected.

2.1.3. Voltage rise and reverse power flow

Traditional centralised power networks involve power flow in one direction only: from power plant to transmission network, to distribution network, to load. These flows are managed through the dispatch of generation yet also network equipment such as tap-change transformers that can adjust network voltages. Other voltage regulation technologies include those that adjust reactive power demand such as Static VAr Compensators (Mizuho, 2008). Voltage settings at the last controllable transformer before the loads are often set at 5–10% higher than the nominal end-use voltage in order to accommodate line losses. These losses and associated voltage drops depend, of course on the actual current flows that are being demanded by the load.

The introduction of distributed generation changes the dynamic of the network because power flows may change significantly and potentially in both directions. In other words, the network becomes an active system with power flows and voltages determined by the mix of centralised and distributed generators as well as the load. With significant levels of DG, localised overvoltage can occur, and the voltage at the load end may be greater than the voltage on the normal supply side of the line—this is known as the voltage rise and can result in reverse power flow (Demirok et al., 2009). Voltage rise is exacerbated when customer demand is at its lowest and distributed generation at its highest, and is especially likely to be a significant issue on long feeders in rural areas (SEGIS, 2007).As discussed below, repeated switching of DG systems on and off in response to overvoltage can impose consequent cycling of network voltage control equipment with associated asset life and maintenance impacts.

In addition to having negative impacts on end-use equipment, voltage rise can have negative customer equity impacts. As discussed below, one of the ways to minimise voltage rise is to restrict DG output when the line voltage exceeds set limits. This is achieved in Japan using inverters called Power Conditioners or Power Conditioning Subsystems that are designed with additional power quality enhancing features that can gradually reduce active power injection. This results in PV output being lost and this might be viewed as unfair to system owners towards the end of the line as the voltage rise will be greater at that point (Mizuho, 2008).[3]

In a small number of locations reverse power protection relays may be installed. These devices are sometimes installed on the low-voltage side of a network transformer to detect and stop current flow 'upstream' towards the transformer. Their normal function is to stop reverse current flow that has occurred because of a fault on the high voltage side of the line, but they can also limit the degree to which DG can contribute to a power system (NREL, 2009). Other negative impacts of reverse power flow include destabilisation of the control systems in voltage regulators where they are not designed for both forward and reverse power flow conditions (McGranaghan et al., 2008).

In many locations and networks, installation of relatively large PV systems does not result in significant voltage rise or reverse power flow issues, but where voltage rise is an issue, four common approaches currently used to minimise voltage rise and applied to the PV systems themselves (NREL, 2009) are:

1. Ensure the PV systems are smaller than the minimum daytime load at the customer metre, so the site should never export power to the grid.
2. A minimum import relay (MIR) can be used to disconnect the PV system if the load drops below a preset value.
3. A dynamically controlled inverter (DCI) can be used to gradually reduce PV output if the load drops below a preset value.
4. A reverse power relay (RPR) can be used to disconnect the PV system if the load drops to zero or reverses direction.

Of these, a DCI set to maximise PV output while avoiding export would allow greatest use of the PV system. However, all these measures not only limit voltage rise but also restrict the potential penetration of PV systems, limiting their contribution to sustainable energy production. Alternatives to these revolve around changes to the network or customer loads, and while they are not currently used, they could be implemented with appropriate policy settings (Whitaker et al., 2008). For example:

1. Decrease the network's series impedance[4] so that it has low voltage drop along its length. While this would come at increased capital cost, it reduces the need for high upstream voltage, leaving more 'headroom' for the PV.
2. Require customer loads to operate at improved power factor, again reducing the need for high upstream voltage.
3. Require customers with large loads (who create the need for the high upstream voltage), to incorporate some form of load-shedding scheme. Shedding of non-critical loads could be triggered when network voltage goes below a specified threshold (which occurs at times of high load), again reducing the need for high upstream voltage.
4. Discretionary loads can be used at times of high network voltage (which occurs at times of low load), to soak up the extra power provided by PV.
5. Storage can also be used to soak up the extra power provided by PV.

All these may cause inconvenience and incur costs for stakeholders who do not necessarily benefit directly from the PV systems. In addition, large loads suitable for load shedding and discretionary loads may not be readily identified.

Thus, optimising PV output, operation of loads and the structure of the network is likely to require appropriate coordination/management of the different stakeholders and options available to them. It essentially requires some mix of investment in lower impedance infrastructure as well as in complex monitoring and control functionality in order to achieve voltage regulation throughout the distribution network. This is not a trivial task and indicates an important role for government and appropriate regulation.

2.1.4. Power output fluctuation

Fluctuations in power output are an inherent problem for DG reliant on renewable energy resources such as sunlight and wind. Short-term fluctuations (seconds) can cause problems with power quality (both voltage and power factor, that can manifest as light flicker or variable motor speed for example), while longer-term fluctuations require back-up generation to maintain power supply. Short-term fluctuations can also result in tap-changers and capacitor switches continually 'hunting' as they attempt to maintain power quality, which results in increased wear of these devices, as well as an increased number of switching surges (McGranaghan et al., 2008).

Three approaches to minimise the impact of such fluctuations are geographical dispersion, forecasting and storage, and these are discussed below. Other options to manage such fluctuations involve

[3] Inverters in European countries such as Germany and Spain do not have features that control voltage by reducing output because the Feed-in-Tariff policies used to drive uptake promote maximum output (PVPS-T10, 2009).

[4] Impedance is essentially a measure of the resistance to an alternating current (AC). It is the equivalent of resistance to direct current (DC).

the use of voltage control and are discussed below in the section on *Power factor correction*. It is likely that coordinated use of all these approaches, which will include the development of novel grid control schemes, will be required to minimise issues caused by power output fluctuation from renewable energy generation.

2.1.4.1. Geographical dispersal. Short-term intermittency of PV can be reduced through geographical dispersal. Very little or no correlation in output over 1 min time intervals has been found for sites as little as 2 km apart (Murata et al., 2009) and even within a single 13.2 MW PV plant (Mills et al., 2009). However, as the assessed time intervals increase, the level of correlation increases. Mills and Wiser (2009) found that while sites 20.5 km apart had close to zero correlation for 1 and 5 min intervals, for 30 min intervals there was almost a 30% correlation, which increased to 50% for 60 min and 80% for 180 min intervals. As expected, the greater the distance between sites, the lower the correlation, with sites 400 km apart displaying only about 15% correlation for 180 min intervals. However for solar technologies at least, dispersal is not as feasible in relatively small areas that are subject to the same weather conditions (for example, on distribution network feeders) and of course is only effective during daylight hours (Eltawil and Zhao, 2010; Mills et al., 2009; Mills and Wiser, 2009).

2.1.4.2. Solar forecasting. The effect of weather can vary on timescales from minutes to seasons and can be quite location-specific, and hence can effect where installations can be sited. Once installations are operational, the impact of inevitable supply fluctuations must be predicted and managed. Solar forecasting techniques are currently being developed through international efforts to provide better forecasting and management tools to manage the variability of intermittent solar energy (both PV and solar thermal). Forewarning that output is likely to diminish could be used to prepare alternative sources of power, and output by solar plants could even be gradually preemptively curtailed in order to reduce the ramp rate required by backup generation (Whitaker et al., 2008).

However, solar forecasting is still in its infancy and there is much work to be done before it can make a significant and effective contribution to management of solar power plant. For example, current prediction systems are generally lacking the small-scale resolution that is required for location-specific forecasts, as well as an understanding of the relationship between the weather conditions and the specific technology for which forecasts are required (Archer and Jacobson, 2005). In addition, all forecasting can do is inform the use of different management options, which still need to be available and then used as appropriate.

2.1.4.3. Storage. Various types of storage including batteries (e.g. lithium-ion batteries, lead-acid batteries, flow batteries), electric double-layer capacitors, Superconducting Magnetic Energy Storage (SMES), flywheels, compressed air and pumped hydro can be used to regulate power output. In addition to reducing the amount of voltage rise on feeders, storage can be used to provide services such as peak shaving, load shifting, demand side management and outage protection. Storage can help defer upgrades of transmission and distribution systems, and can help with 'black starts' after a system failure (Denholm et al., 2010). It can also help provide several ancillary services, including contingency reserves (spinning reserve, supplemental reserve, replacement reserve), and voltage and frequency regulation (Kirby, 2004; Whitaker et al., 2008; Inage, 2009).

As a result of these various benefits, there has been increasing interest in the use of storage at the distribution level, however the costs, benefits, maintenance, reliability and life cycle of storage systems are still being researched (Ueda et al., 2008, 2007; Nakama, 2009; Whitaker et al., 2008; Nishikawa, 2008; Shimada et al., 2009; Manz et al., 2008). Systems having separate batteries associated with each DG system, separate batteries associated with each DG system but under coordinated operation, and a single battery at the community level have been investigated (Kurokawa et al., 2009).

For recent reviews of the technology options for storage see (Bradbury, 2010), and for the use of large-scale storage to regulate power output as well as power quality see Inage (2009) and Denholm et al. (2010), while Perez et al. (2010) present costings of the storage requirements of large-scale PV penetration. For small-scale RE systems, lead-acid batteries remain the lowest cost and most reliable option, with flywheels, supercapacitors and flow batteries now being demonstrated on medium sized systems and nickel-cadmium batteries used for smaller applications. These benefits may make storage more cost-effective for a DG system, and similarly, installation of a battery specifically to provide one or more of these functions may provide an opportunity for a DG system to be installed and receive a degree of backup (SEGIS-ES, 2008).

In summary, while batteries and other forms of storage have significant potential to enable higher penetration of many types of DG, realising that potential will not only require careful consideration of how best to develop storage options, but also how to integrate them into electricity networks along with DG.

2.2. Power factor correction

Poor power factor on the grid increases line losses and makes voltage regulation more difficult. Inverters configured to be voltage-following are generally set to have unity power factor,[5] while inverters in voltage-regulating mode provide current that is out of phase with the grid voltage and so provide power factor correction. This can be either a simple fixed power factor or one that is automatically controlled by, for example, the power system voltage (Passey et al., 2007).

A number of factors need to be taken into consideration when using inverters to provide power factor correction. The first is that to provide reactive power injection while supplying maximum active power, the inverter size must be increased. For example, increasing the inverter size by 10% means the reactive power capability can be increased from zero to nearly 46% in the maximum PV power generation condition (Liu and Bebic, 2008).

The second factor to be taken into consideration is that the provision of reactive power support comes at an energy cost.[6] For example a 10 kVA inverter, which is 94% efficient at full power output, will be dissipating 600 W. When that same inverter is delivering 10 kVAr and no real power the inverter is 0% efficient and will still be consuming 600 W. The owner of the inverter may not directly benefit from the VAr compensation it provides but they will bear the cost of the energy loss incurred by the inverter in providing the compensation.

The third factor is that simple reactive power support can probably be provided more cost-effectively by SVCs or STATCOMS—unless of course the inverter is to be installed regardless as part of a DG system. Their energy loss is also considerably less than for the equivalent inverter VAr compensation. The main advantage of inverter VAr compensation is that it is infinitely variable and very fast in response to changes in the power system. In areas where rapid changes in voltage are experienced due to large load transients (e.g. motor starts) or

[5] Note that current-source inverters can be specially configured to operate outside unity power factor, however the vast majority of commercially available inverters used for PV are not.

[6] Inverters can provide reactive power in the absence of DG output. The energy cost would then be drawn from the grid.

where only a small range of VAr control is required, then an inverter VAr compensator may be justified.

The fourth factor is that while this sort of reactive power compensation is effective for voltage control on most networks, in fringe of grid locations system impedances seen at the point of connection are considerably more resistive, and so VAr compensation is less effective for voltage control. In these situations, real power injection is more effective for voltage regulation. Thus, PV inverters connected to fringe of grid lines can provide voltage regulation at the point of connection provided the real power input of the inverter (which can only occur when there is sufficient solar insolation or some form of storage backup) correlates in time with the load on the system (Passey et al., 2007; Demirok et al., 2009).

Studies into the use of inverters to regulate network voltage at high PV penetrations have found that in order to achieve optimal operation of the network as a whole, some form of centralised control was also required (PVPS-T10, 2009; Uemura, 2008; Morozumi et al., 2008; Sulc et al., 2010; Turitsyn et al., 2010). It has also been found that reactive power injection by inverters may be limited by the feeder voltage limits, and so coordinated control of utility equipment and inverters, as well as additional utility equipment, may be required (Liu and Bebic, 2008).

In summary, PV inverters are capable of VAr compensation to assist with voltage control on the grid, although this requires larger inverters and comes at an energy cost. How the VAr compensation is valued and who pays for the energy has generally not been addressed. Although large load transients may justify an inverter, SVCs or STATCOMS may be a more cost-effective source of VAr compensation. Of course, where an inverter is already paid for as part of a separate DG system, it is likely to be the more cost-effective option. The effectiveness of reactive power injection for voltage control is also influenced by location, and it is likely that coordinated control of inverters and the existing utility equipment may be required.

2.3. Frequency variation and regulation

Frequency is one of the more important factors in power quality. The frequency is controlled by maintaining a balance between the connected loads and generation. It is controlled within a small deviation: for example, in Japan the standard is 0.2–0.3 Hz; in the U.S. it is 0.018–0.0228 Hz; and in the European UCTE it is 0.04–0.06 Hz (Inage, 2009).

Disruptions in the balance between supply and demand lead to frequency fluctuation—it falls when demand exceeds supply and rises when supply exceeds demand (Inage, 2009). Power systems contain a number of sources of inertia (e.g. large rotating generators and motors), which result in considerable time constants involved in frequency movements when there is a mismatch between load and generation. The time constants depend of course on the size of the system and how well it is interconnected.

Frequency regulation is maintained by control loops built into the power generating sources on the network. In conventional grids, generators and turbines use an actuator to control the flow of fuel, gas or steam to maintain the required frequency. It is the performance of these actuators, turbo devices and inertia of the generators that give the frequency sturdiness (Asano et al., 1996; Kirby, 2004).

With the increasing penetration of intermittent energy sources such as wind and solar, frequency control becomes more difficult. Although the contribution to power fluctuation from PV systems is currently much smaller than that from wind generators, as the number of grid-connected PV systems increases, the issue of frequency fluctuation may become more noticeable (PVPS-T10, 2009). One study found that 10% penetration of PV required a 2.5% increase in conventional frequency control, while a 30% PV penetration required a 10% increase (Asano et al., 1996).

DG inverters may be able to help with frequency control. Inverters can provide frequency control in milliseconds, which is significantly faster than conventional generation (Inage, 2009). Of course, grid-connected inverters would only be able to control frequency to the extent that changes in their real power output actually influences the overall (grid wide) supply–demand balance. Generally they will not be able to change the frequency unless they represent a significant amount of generation—such as in relatively small grids. In addition, special control algorithms would need to be developed to take advantage of the fast response times, and at present DG is unproven in this application.

In a number of circumstances DG may be unable to provide frequency support. Inverters can only provide frequency control when they can inject power into the network (e.g. during daylight hours for PV) (Whitaker et al., 2008), and DG linked to combined heat and power plant are restricted in their ability to provide frequency regulation because of their thermal loads (Kirby, 2004). Most importantly, where inverters are configured to disconnect from the grid when the frequency moves outside set limits (as a form of islanding detection), their ability to provide frequency support may be compromised. If the power system has lost generation for some other reason (e.g. a lost transmission line) and the system load is greater than the connected generation, then the frequency will start to fall. If it falls outside the trip limits then all the DG will also disconnect, exacerbating the power imbalance and leading to a need to shed more load to avert a complete system shutdown (Whitaker et al., 2008). New frequency ride through systems that do not interfere with the anti-islanding protection systems will need to be developed to cope with this situation as penetration levels increase.

2.4. Harmonics

Harmonics are currents or voltages with frequencies that are integer multiples of the fundamental power frequency. The standard frequency is 50 or 60 Hz depending on the country, and so a harmonic in a 50 Hz country could be 100, 150, 200 Hz, etc. Electrical appliances and generators all produce harmonics and are regulated under the International Electrotechnical Commission (IEC) Electromagnetic Interference (EMI) standards.[7] However in large volumes (e.g. computers and compact fluorescent lamps), these harmonics can add up to cause interference that can result in vibration of elevators, flickering of TV monitors and fluorescent lamps, degradation of sound quality, malfunctioning of control devices and even fires (PVPS-T10, 2009).

The existing inverter standards in Australia (AS4777.2) and in the US (UL1741) for small PV systems require that the inverter must produce less than 5% total harmonic distortion (THD) on injected current with tight limits on specific harmonics. This is much more stringent than for loads of equivalent rating (as specified in the IEC61000 series of documents). For PV, Europe and the UK rely on similar standards to those for loads, i.e. the IEC61000 series of standards. Most grid-connected inverters for DG applications put out very low levels of harmonic current, and because of their distribution on the network are unlikely to cause harmonic issues, even at high penetration levels (Infield et al., 2004; Latheef et al., 2006; Nishikawa, 2008).

Inverters may be able to help with correcting harmonics, however as discussed below, they must be configured to provide

[7] This is because they need direct current (DC) power or AC at a different frequency to that supplied, and use power electronics technologies to change the grid AC to the desired current waveform, and in doing so generate harmonics in the grid.

out of phase current, and the equity impacts of harmonic correction need to be taken into account.

There are generally two types of control schemes used in PV inverters: as a sinusoidal voltage source or a sinusoidal current source. Most PV inverters at present are the current-source type because this makes it easier to meet grid-connection standards and provide rapid overcurrent protection. However, many loads expect the power system to be a sinusoidal voltage source and many of them demand non-sinusoidal currents and currents out of phase with the supply voltage. The net effect of a large number of loads of this type is that the supply system has to provide a considerable amount of out of phase and harmonic currents, and the flow of these currents on the network creates harmonic voltages that then can affect other loads. Adding PV inverters which provide sinusoidal currents at unity power factor means that the inverters supply the in-phase sinusoidal component of the loads and the grid is left to still supply out of phase current and harmonics. Thus, while current-source PV inverters generally do not make the situation worse, they do not contribute to the supply of the out of phase and harmonic currents required by loads. Note that current-source inverters can be specially configured to provide reactive power, however for the vast majority of commercially available inverters used for PV, this facility is not used i.e. they are locked at unity power factor. The voltage source type of inverter could assist by contributing the harmonic currents required by loads but this type of inverter is at present not common in the market place, and may be illegal in some jurisdictions. Currently, inverters are not required to be characterised as being voltage source or current source and hence it is very difficult for purchasers of equipment to select a particular type.

Even when a voltage source inverter is used to help correct poor harmonic voltage, and so the inverter produces harmonic currents to assist in correcting the grid voltage, its energy output is reduced. This is equitable provided the owner of the inverter is also the cause of the harmonics on the grid and so they are assisting with correction of their own problem. However the owner of the inverter may be experiencing high harmonic flows, and so reduced energy output, because of the poor harmonic performance of other customers on the power system. This is another reason why current source inverters are common—their output is not generally affected by the grid's voltage harmonics.

Harmonics can also be eliminated using passive and active filters, which are generally cheaper than inverters. Passive filters are composed of passive elements such as capacitors or reactors, and absorb harmonic current by providing a low-impedance shunt for specific frequency domains. They come in two forms: tuned filters (which are targeted to eliminate specific lower-order harmonics) and higher-order filters (that can absorb entire ranges of higher-order harmonics). Active filters detect harmonic current and generate harmonics with the opposite polarity for compensation. They are better than passive filters because they can eliminate several harmonic currents at the same time, they are smaller and quieter, and they do not require a system setting change even when a change occurs in the grid (PVPS-T10, 2009).

In summary, while the most common type of inverters (current-source) do not create harmonic distortion, they also do not provide the harmonic support required from the grid. Voltage-source inverters can provide harmonic support but do so at an energy cost and there are a variety of harmonic compensators that are likely to be cheaper. Labelling that identified the type of inverter (voltage or current source) would help purchase of voltage source or current source inverters as required, as would financial compensation for reducing energy losses if voltage source inverters are installed. Note that, unless specially configured, PV inverters disconnect from the grid when there is insufficient sunlight to cover the switching losses, meaning that no harmonic support would be provided outside daylight hours. Of course, requiring loads to not create excessive harmonics or THD in the first place could have a significant and beneficial effect.

2.5. Unintentional islanding

Unintentional islanding occurs when distributed generation delivers power to the network even after circuit breakers have disconnected that part of the network from the main grid and associated generators. This can cause a number of different problems (SEGIS, 2007; McGranaghan et al., 2008; Coddington et al., 2009):

(i) Safety issues for technicians who work on the lines, as well as for the general public who may be exposed to energised conductors.
(ii) It may maintain the fault conditions that originally tripped the circuit breaker, extending the time that customers are disconnected.
(iii) Possible damage to equipment connected to the island because of poor power quality (e.g. where inverters are in voltage-following mode).
(iv) Transient overvoltages caused by ferroresonance and ground fault conditions are more likely when an unintentional island forms.
(v) Inverters could be damaged if the network is reconnected while an island of DG exists.
(vi) It is possible for a network that does not have synchronising capabilities to reclose in an out of phase condition, which can damage switchgear, power generation equipment and customer load.

Since islanding is a well-known problem, grid inverter technology has developed to include anti-islanding features as are required by local regulations and standards. Islanding detection methods can be divided into five categories: passive inverter-resident methods, active inverter-resident methods, passive methods not resident in the inverter, active methods not resident in the inverter, and the use of communications between the utility and DG inverter (Eltawil and Zhao, 2010).

(i) Passive inverter-resident methods involve the detection of the voltage or frequency at the point of grid connection being over or under specified limits.[8] These methods also protect end-users' equipment.
(ii) Active inverter-resident methods involve active attempts to move the voltage or frequency outside specified limits—which should only be possible if the grid is not live.[9]
(iii) Passive methods not resident in the inverter involve the use of utility-grade protection hardware for over/under frequency and over/under voltage protection.
(iv) Active methods not resident in the inverter also actively attempt to create an abnormal voltage or frequency or perturb the active or reactive power, but the action is taken on the utility side of the inverter connection point.
(v) Communications between the utility and DG inverter methods involve a transmission of data between the inverter or

[8] They may also detect the rate of change of power and voltage, and trip the inverter offline if these exceed a preset value. Harmonic detection methods (that detect either the change of total harmonic distortion or the third harmonic of the PV output voltage) and phase jump detection methods (that monitor the phase difference between PV output voltage and the output current) can also be used (Yu et al., 2010).

[9] Active methods can also include monitoring changes in grid impedance after the injection of a particular harmonic or a sub-harmonic (Trujillo et al. 2010).

system and utility systems, and the data is used by the DG system to determine when to cease or continue operation.

As briefly outlined below, each of these approaches has strengths and weaknesses.

Passive methods:

– Can malfunction due to interference from a cluster of inverters (NEDO, 2006; SEGIS, 2007).
– May fail to detect islanding when the reactive power of the DG system and the load on the customer side of the inverter are the same (this is known as the non-detection zone), especially where inverters can vary their power factor because this allows them to best match load and supply to maximise efficiency (Trujillo et al., 2010; Eltawil and Zhao, 2010).
– As the resonant frequency of the local load approaches the local grid nominal frequency, the inverter may not detect that the line voltage has been cut and the automatic cut-off feature will not function (Yu et al., 2010).

Active methods:

– Can in theory have a minor but negative impact on grid power quality when there are a number of inverters on the same line and interference from the signals occurs. Pulses associated with impedance detection for anti-islanding can accumulate in high penetration scenarios and may cause out-of-specification utility voltage profiles. Such power quality impacts could then interfere with islanding detection capabilities. However, most inverters incorporate internal controls to minimise these problems and no practical impacts have been reported so far (Whitaker et al., 2008; PVPS-T10, 2009).
– Are considered to be incompatible with microgrids because (i) they cannot readily be implemented at the point of connection of the microgrid to the main grid and (ii) the active attempts to move the voltage or frequency outside specified limits work against a seamless transition between grid-connected and stand-alone modes (Whitaker et al., 2008).
– Have no uniform standards and so there is a diverse mixture of control algorithms on networks. Some algorithms attempt to drift the frequency up, some down, some depend on the load generation match and some do not drift but use impedance measuring current pulses. The problem with this situation is that there is an increased risk of forming a stable island because a stable frequency operating point may be reached. It appears that this may have happened in Spain on a 20 kV feeder for a brief period of time several years ago (Pazos, 2009).

Active and passive methods:

– Can conflict with inverters injecting reactive power during sags to help boost network voltage, and adds complexity to the control algorithms (Whitaker et al., 2008; PVPS-T10, 2009).
– Can fail when the DG uses voltage regulation and governor control characteristics, because the DG output may adapt to the islanded system load demand without reaching the voltage or frequency trip points. However, such control characteristics are not generally used for DG, except when they are used as backup power sources independent of the grid (Walling and Miller, 2003).

In addition, on a weak grid, an inverter may cut out prematurely or, more likely, may not reclose (i.e. reconnect to the grid). For example, Australian Standard AS4777 specifies that the autoreclose function needs the grid to be stable for 60 s, which on a weak grid may not occur for some time. Networks are generally designed to reclose after 10 s and so for the next 50 s the DG will not be providing network support. To increase DG's ability to provide line support, the network operator could specify more reasonable tolerance limits and shorten the reclose time. Some form of short-term storage could also be used to bridge the gap between the network and the PV inverter reclosing (Passey et al., 2007).

According to Whitaker et al. (2008) and McGranaghan et al. (2008), the best options to improve islanding detection are based on improved communications between the utility and the inverter. These could help overcome the problems associated with failure to detect an island condition, with false detection of island conditions, and failure to reclose and so provide grid support. For example, power line carrier communications (PLCC) could be used as a continuity test of the line for loss-of-mains, fault, and islanding detection—but only once technical challenges such as having a continuous carrier are solved. However, because such a system is unlikely to be perfect, it should include some redundancy in the form of autonomous active island detection options. Communications-based systems are also likely to be higher cost (Ropp, 2010).

In summary, passive, active and communications-based islanding detection methods have a number of issues that need to be resolved. It is likely that different mixes of these methods will be required in different locations, and that phasing out or replacing less effective methods will not be a simple task, and will likely involve a coordinated approach by government, utilities and installers and owners of DG systems.

2.6. Other issues

Other issues, that are likely to be of less importance and for space reasons have not been included here, include fault currents and effective grounding (McGranaghan et al., 2008), DC injection and high frequency waves (PVPS-T10, 2009) and of course the impacts of aggregated DG on subtransmission and transmission networks (McGranaghan et al., 2008).

3. Factors that influence how these issues are addressed

As discussed in the previous section, there are many potential technical issues associated with connection of DG to electricity networks, especially at high penetrations. While some of these impacts may be beneficial in some circumstances such as reduced losses and peak current flows, some adverse impacts are likely at significant penetrations whilst others may also be possible in low penetration contexts. The challenge is to facilitate the deployment of DG in ways that maximises their positive grid impacts whilst minimising adverse impacts, within the context of wider societal objectives associated with DG uptake. The types of technical solutions likely to be required to achieve this may sometimes be different in different countries, simply because they have different types of electricity networks, renewable energy resources, mixtures of conventional and renewable energy generators, correlations between renewable generation and load, government priorities and, ultimately, technical capacities within utilities, government and the private sector.

DG of course does not represent the first disruptive set of technologies for electricity industry arrangements. For example, wind energy represents the first major highly variable and somewhat unpredictable generation to achieve high penetrations in some electricity industries. As such, it has tested, and in some cases driven changes to, current technical and wider industry arrangements. These include low voltage ride through requirements, technical connection standards and more formal participation in electricity markets (MacGill, 2009). As such, the transition, with growing penetrations, from wind energy being treated by the electricity industry as negative load, through to its current formal and active participation in many electricity industries, provides an interesting analogy to the transition that DG must now also make. However, DG adds a whole new set of distribution network issues that we are still coming to terms with.

Recent high financial support for PV, such as Feed-in-Tariffs in Europe and grant-based support in Australia have led to very rapid increases in installed PV capacity, with institutional and electricity sector capacity falling behind in some cases. Problems have been exacerbated when such financial support has been linked to time or capacity-based caps, which have encouraged a rush to install. Poor quality components and installations have often resulted, which will cause problems for the DG sector in future.

Thus, addressing these technical problems requires more than just the technical solutions described above. It will require policy and regulatory frameworks to coordinate the development and deployment of the different technologies in ways most appropriate for particular jurisdictions. These frameworks will be different for different countries, and so no single approach will be appropriate worldwide. Thus, this section discusses the non-technical factors that influence which types of technological solutions are most likely to be appropriate, and provides suggestions for increasing the likelihood of best practise.

3.1. *Role of government, regulator and electricity utilities*

Irrespective of the jurisdiction in question, if governments choose to put in place appropriate regulation, standards and agreements, as well as the related mechanisms for enforcement, then appropriate technological solutions for adverse DG network impacts are more likely to be implemented. Of course for this to occur, the government needs to know what is required, based on industry research and expert advice.

Government and educational institutions may need to assist with information dissemination (regarding new rules and regulations), promotion of the use of technologies and facilitation of training for the appropriate public entities and private companies. Training could be a very important factor in some countries, because inadequate technical capability will restrict the uptake of best practices, even if the willingness is there. For example, the Government of Fiji and the Fiji Electricity Authority (FEA) have published ambitious targets for renewable energy generation (Department of Energy, 2006; FEA, 2010), however, technical capacity on the ground to implement appropriate technologies and solutions, both within the Government itself and within the private sector to which the Government and FEA are increasingly looking, is still lacking (Singh, 2009; Hook, 2009). In 2010, the newly formed and largely PV-industry led Sustainable Energy Industry Association of the Pacific Islands (SEIAPI), noted the urgent need for compilation and dissemination of guidelines for installation, operation and maintenance of grid-connect PV systems (SEIAPI, 2010). Members working in the industry were willing to apply standards and be regulated but needed this information to be standardised and disseminated, with training opportunities set-up with appropriate educational service providers.

This all assumes a certain level of capacity within government and utilities, and if this is not immediately available then delays in developing and establishing standards and enforcement may affect the timeline of technology take up, or lead to what were avoidable adverse impacts. Poor delivery early on may then impact longer-term confidence in the measures proposed.

Whether electricity utilities are privately or government owned should not in itself be an issue, assuming that all utilities are subject to and held to equivalent standards and regulations. An independent energy regulatory framework is also almost certainly required for such standards and regulations to be enforced. If utilities still retain a regulatory role, conflicts of interest may arise. This has been the case in Fiji and Palau, where the state-owned and self-regulating utilities have been hesitant to allow the widespread (e.g. household) take-up of solar PV DG until grid-connection standards and agreements are developed. However, with limited resources available to them and low incentive to act, the utilities do not prioritise the development of these documents themselves and so progress stagnates.

Where electricity retailers and/or network operators – whether publicly or privately owned – have their income directly linked to kWh sales, DG can be seen as a threat to revenue (as can energy efficiency) and hence the electricity sector may hinder DG proposals via active obstruction, or passive resistance via long delays and high costs for interconnection. If a utility is self-regulating, they may set the feed-in-tariff too low for DG to be attractive, thus deterring DG development and protecting their own interests. This is the case in Fiji, where hydropower investors have argued for some time that the FEA tariff is too low to encourage investment (Hydro Developments Limited, 2011).

3.2. *Institutional and regulatory barriers*

The main barrier of this type appears to be existing standards that were originally developed for DG when it was at relatively low penetrations. The standard most commented on is IEEE 1547, which is currently being expanded in light of higher penetration in order for DG to provide ancillary services such as local voltage regulation, as well as to improve the speed at which unintentional islands are cleared (McGranaghan et al., 2008). Requirements such as low voltage ride through could also be included into standards, as they are in Germany. Frequency limits can also be broadened, helping to avoid large amounts of DG prematurely disconnecting from the grid and so causing more significant disruptions, as has recently happened in Alice Springs, Australia (Hancock, 2011). Standard processes need to be very responsive to rapid changes as penetration levels and potential solutions develop.

Similarly, as research in DG is published and international standards change over time, it is important to prevent national regulations which may be out of date from obstructing the application of new best practices developments in DG. A possible solution is national committees which follow developments of international standards and research and update relevant national standards when required.

Otherwise, either a lack of appropriate standardised grid-connection agreements and requirements, or the presence of inappropriate agreements and requirements, can inhibit the uptake of best practise DG. Indeed, the absence of PV-specific standards for grid connection has in the past been a significant barrier to uptake in many IEA countries (Panhuber, 2001).

Utilities may place limitations on the amount of DG that can be connected to their networks (e.g. limiting the amount of DG to being less than the minimum expected load) if they feel that their network is inadequately protected from low quality renewable technologies and installations or if they are unaware of the latest best practise technological advances which make grid-integration safer and easier. Existence and dissemination of installation and product standards can engender more "trust" in renewables and DG more generally from the utility side.

It is possible to achieve a virtuous cycle, where application of the most appropriate technologies can help to overcome institutional and regulatory barriers, since the use of such technologies should gradually allow much higher penetrations. As more technologies are demonstrated, there will be increased confidence in grid-connected renewables and even utilities that might generally oppose DG would have the opportunity to visit existing best practise installations before deciding on their future DG policy.

3.3. Existing electricity infrastructure

Where growth in demand requires new infrastructure to be built, there is an opportunity for that infrastructure to be constructed from the ground up with the most appropriate technologies and grid architecture, and so best practices can be applied—ideally up to the standard of a smart grid. Where demand growth requires existing infrastructure to be augmented, this may also provide an opportunity for best practices to be applied. It is worth noting that there may be conflicts of interest between the need for energy efficiency to limit growth and then reduce demand in absolute terms, and the ease of applying best practices. Where best practices can be retrofitted to existing infrastructure or incorporated into asset replacement programs, demand growth is not required and the nature of the existing infrastructure is less relevant.

For example, all the approaches that can be integrated into newly connected DG, such as ancillary service capabilities in inverters, storage and geographical distribution of DG, can be applied independently of the existing infrastructure—as can avoiding voltage imbalance by connecting the same amount of new DG to each phase of a network.

Applying best practices to existing DG would not so much be limited by the existing network infrastructure as by the existing systems, especially inverters, as these would need to be either reconfigured or replaced. The addition of storage to existing DG should not be affected by existing infrastructure, as long as there is space for it to be installed—although charge regulators would need to be added to most inverters currently used for grid applications. Again, ensuring that the same amount of existing DG is connected to each phase of a network can be retroactively applied at modest expense and effort.

Addressing unintentional islanding by using improved active detection methods can be included into new DG but would require inverter replacement for existing DG. Integrated communications-based control systems are most likely to be readily applied to new-build or significantly upgraded networks, such as smart grids, but might still be applied to existing networks. Fully integrating a communications-based control system with redundant autonomous passive or active methods, would again be easier (and cheaper) in new-build networks, but could still be done for existing infrastructure.

Technological approaches that would be most restricted by the existing infrastructure are those that require changes to the infrastructure itself, such as reducing its series impedance.

Of course, a fully integrated smart grid, that included best practices in system architecture, including possible mesh/loop network structures and the technologies required to operate them, could only be purpose-built from the ground up. In this case the nature of the existing infrastructure is also irrelevant, as such a smart grid could only be built to meet increased demand or supply new green-field developments.

3.4. Relative availability of conventional and renewable resources

The relative availability of conventional and renewable resources has the most impact on the *need* for particular technological solutions to be applied, rather than on the *likelihood* of their introduction. Generally, the greater the uptake of renewables, the greater the need for technological solutions to deal with grid integration. Where no formal regulation and standards are in place, utilities may restrict uptake of renewables to the grid. This could create a bottle-neck for renewable energy applications until regulations and standards are put in place, which comply with best practices.

To the extent that the use of conventional resources is restricted, the rate of uptake of renewable energy will be increased. The use of conventional resources may be restricted for a variety of reasons including: access to the resources themselves (e.g. through lack of indigenous resources or restrictions on imports); the impact that importing them has on the national balance of payments; the relatively high cost, especially if a price is placed on carbon; any pollution impacts; and conventional power stations being too large-scale for the purpose required.

The need for particular technological solutions to then be used to address any grid impacts will depend on the type and particularly the scale of renewable energy resource to be used. Resources such as bioenergy, geothermal and hydro, that are more likely to be dispatchable and able to provide constant power output, will often be of transmission network scale and even at smaller scale will often be direct AC generation and so not use inverters. Other smaller scale DG should have little requirement for anything beyond standard inverter technology and grid architectures. Solar thermal electricity technologies are unlikely to be of the scale to be connected to distribution networks, but would have a greater requirement for new technology especially if they do not include some form of storage. Similarly, small-scale wind is deployed at relatively low levels, but where it is deployed, is more likely to result in the need for best practices to be applied, as is PV, as both these resource are intermittent in nature and can affect, for example, local voltage and, in smaller grids, frequency.

The nature of the load profile will also influence the need for particular technologies. Where it is well matched to renewable energy supply there will be less need for storage or demand management, and voltage rise may be less of a problem. In these circumstances, DG will also be better placed to provide ancillary services and so implementation of appropriate technologies will provide more value to the electricity network.

3.5. Stages of economic and technical development

Different countries are in different stages of economic and technical development, which means that different issues may need to be addressed, and so different types of technologies are likely to be appropriate. Even within countries, different regions, with different renewable energy resources, socio-economic conditions and technical capacities may need different treatment.

For example, many Asia-Pacific countries may have one large main island with high rainfall and mountainous landscape making grid-connected hydro resources a promising technology for development, while also having a large number of isolated, small low-lying islands where there would be no hydro but a very good solar resource for solar PV mini-grid development.

It is also possible that grids will not be so robust in less developed areas and economies, and so will be less able to withstand rapid fluctuations in power output. Of course, it is also possible that end-users may already have significantly lower expectations of power quality, and more robust electrical loads. To the extent that such networks are more likely to be in need of technologies that can deal with such fluctuations (e.g. inverters with wide voltage fluctuation thresholds), they may also have lower economic and technical capacity to apply best practices, and so should be targeted for technical capacity building. Thus, service providers on small islands and isolated rural areas should receive priority training in technical operation and maintenance of renewable energy technologies and how to select appropriate technologies for the areas where they are trying to provide new or maintain existing electricity supply.

3.6. Local expertise in renewable and associated technologies

Of most relevance here is the local expertise in DG technologies and the impacts of different types of DG technologies on the networks. In large part this can be driven by requirements laid down by governments (provided they are enforced), as such requirements will drive the development of the expertise required to meet them. Adequate training should also be made available for energy professionals by appropriate government, industry, and educational bodies.

Industry associations, if they exist, can help lobby for application of best practices. These are often renewable energy resource-specific (e.g. hydropower associations, solar PV associations) but sometimes are not. These associations can provide services such as information dissemination, training and promotion of best practices for the technologies they represent.

To a certain extent, the installation of DG in developing countries is undertaken by external expertise. Such expertise can bring in the knowledge from developed countries, but it is important that knowledge transfer occurs to drive capacity building in local expertise and to allow the gradual scaling down of reliance on external expertise in the medium to long-term. The REP-5 Programme (Federated States of Micronesia, Nauru, Niue, Palau and the Republic of the Marshall Islands, 2006–2010) installed over 250 kWp of grid-connected PV and was largely implemented by external expertise in the Programme Management Unit and short-term international consultants and companies. However, the European Union funded-programme also conducted more than 15 renewable energy training sessions for in-country utility, government and private sector staff, hired local staff to work alongside overseas contractors and assisted the governments of the target countries to develop appropriate policies for renewable energy technologies (Syngellakis et al., 2010).

What has been found to be critical, in both developed and developing countries, is ongoing maintenance of DG. This means that appropriate mechanisms need to be in place to ensure that inverters and any other enabling technologies (e.g. batteries) are maintained on an ongoing basis. This can be a difficult issue if project finance is based on up-front capital cost only, with separate provision needed for ongoing maintenance. This has been typical of aid-based finance, but is also an issue for up-front grant-based support in developed countries.

Regardless of the amount of training given to local operators, a post-installation assistance programme should be put in place to monitor the performance of any installed system. Capacity to monitor renewable energy installations or to deal with manufacturers to replace broken down components, takes time to build, despite the local operators having been trained in the operation and maintenance of the installations during the project. Many past and present aid-based projects have not taken this into account, resulting in failure of the installed energy generation system or even worse, damage to equipment connected to the DG energy supply.

Ultimately, the ability to apply best practise design, installation and maintenance of grid-connected renewables in the long-term will depend on the local expertise available. This means that energy professionals in the public and private sector need to be trained on an on-going basis, so that as technologies, products, installation methods, standards, regulations and best practices evolve, knowledge in the national industry also evolves.

4. Conclusion

When considering increasing levels of penetration of DG in electricity networks, it must be remembered that the original design of networks did not envisage DG in the distribution system. The design of networks was based on more centralised generation sources feeding into the transmission system, then subtransmission and distribution systems. The security, control, protection, power flows, and earthing of the network was predicated on a centralised generation model with a small number of source nodes, with communication and control linking major generators and nodes. When installing DG, very low penetration on a distribution system can generally be tolerated without significant problems as described in this paper. The threshold where problems occur depends heavily on the configuration of the network, length of lines involved (and hence impedances) and the concentration and time dependence of the load and generation in the area.

When penetration of DG rises above the network's minimum threshold, more significant issues can arise in the some networks. More DG may be accommodated by making changes to the network such as minimising VAR flows, power factor correction, increased voltage regulation in the network and careful consideration of protections issues such as fault current levels and ground fault overvoltage issues. In many countries which have actively encouraged DG in recent years, the level of penetration is already at this middle stage and significant network modification is under consideration to allow expansion of DG without taking the next significant step of major design and infrastructure change.

At high levels of penetration, a point is reached (which again is very network dependent) where significant changes have to be made to accommodate these higher levels of DG. This will probably require significant overall design and communications infrastructure changes to accommodate coordinated protection and power flow control. This third stage is very much in the research area and, although there are a number of communications protocols developed for distributed generation, the use, coordination and the design philosophy behind this are very much under research and development, the microgrid concept being one example. The full use of microgrids within the wider electricity network is again still very much in the research and development stage.

There is increasing pressure to quickly implement DG on electricity networks, but to do this at medium to high penetration levels will require careful preparation and development of safe and carefully integrated protection and control coordination.

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